BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN RE:	)	
APPROVAL, DISAPPROVAL AND	)	
PROMULGATION OF IMPLEMENTATION	)	EPA Docket No.
PLANS; NEBRASKA; REGIONAL HAZE STATE	)	EPA- R07-OAR-2012-1058
IMPLEMENTATION PLAN; FEDERAL	)	
IMPLEMENTATION PLAN FOR BEST AVAILABLE	)	
RETROFIT TECHNOLOGY DETERMINATION	)	
(77 Fed. Reg. 40130, July 6, 2012)	)	
	)	

PETITION FOR RECONSIDERATION

Nebraska Public Power District ("NPPD") respectfully requests the U. S. Environmental Protection Agency ("EPA") grant partial reconsideration of the above-captioned rule (the "Final Rule") as hereinafter requested. NPPD, a public corporation and political subdivision of the State of Nebraska, provides the electricity requirements in all or parts of 86 of Nebraska's 93 counties. NPPD provides retail service and total or partial wholesale electric service to over one million Nebraska citizens. NPPD provides the entire electricity supply in 80 retail communities it serves and the entire wholesale supply of electricity to 52 municipal electric utilities and 25 public power districts and cooperatives. Several other utilities in Nebraska receive part of their power supply from NPPD.

In the Final Rule, EPA found that many portions of Nebraska's Regional Haze State Implementation Plan ("SIP") were satisfactory. *See generally* 77 Fed. Reg. 40149 (July 6, 2012). However, EPA's Final Rule disapproves Nebraska's SO_2 BART determination for NPPD's Gerald Gentleman Station ("GGS"). *Id.* at 40152. EPA disapproved Nebraska's long-term strategy insofar as it relied on the SO_2 BART determination for GGS. *Id.* at 40151. Although not set forth in the Proposed Rule, EPA disapproved the cost estimates for NO_x while finalizing EPA's proposed approval of the Nebraska SIP with respect to BART for NO_x. *Id.* at 40159. EPA, for the first time in the Final Rule, disapproves Nebraska's $40 million/deciview cost threshold. *Id.* at 40156. Finally, the Final Rule confirmed EPA's proposed Federal Implementation Plan ("FIP") relying on the Transport Rule as an alternative to BART. *Id.* at 40160.

THE EPA UNLAWFULLY USURPED THE AUTHORITY OF THE STATE OF NEBRASKA

Congress provided the States with the primary authority to determine BART eligible sources and to determine what best available retrofit technology would be suitable for such source. The Clean Air Act ("CAA") states:

> in determining best available retrofit technology, the ***State*** (or the Administrator in determining emission limitations which reflect such technology), shall take into consideration the cost of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology;

42 U.S.C. § 7491(g)(2) (emphasis added).

The United States Court of Appeals for the D. C. Circuit has recognized EPA's limited role in developing Regional Haze plans, stating that the CAA "calls for ***states*** to play the lead role in designing and implementing regional haze programs ..." *American Corn Growers Assn. v. EPA,* 291 F.3d 1, 2 (D.C. Cir. 2002) (emphasis added). Section 101 of the CAA, in describing the Congressional purpose of the Act, states that "air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source *is **the primary responsibility of States and local governments**.*" 42 U.S.C. § 7401(a)(3) (emphasis added).

In *Virginia v. EPA*, the Court found that the CAA "expressly gave the states initial responsibility for determining the manner in which air quality standards were to be achieved" and cited the U. S. Supreme Court for the proposition that:

> ***The Act gives the Agency no authority to question the wisdom of a State's choices of emission limitations*** if they are part of a plan which satisfies the standards of § 110(a)(2), and the Agency may devise and promulgate a specific plan of its own only if a State fails to submit an implementation plan which satisfies those standards. § 110(c). Thus, so long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards for ambient air, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation.

108 F.3d 1397, 1406-1407 (D.C. Cir. 1997) (internal quotations omitted) (emphasis added).

It must be emphasized that the requirement that the States, not the EPA, make BART determination decisions was a key part of a compromise that resulted in CAA § 169A being enacted. H.R. 6161, 95th Cong. (1977). The House Bill, H.R. 6161, did not initially reference States as making BART determinations. Those parts of § 169A(b)(2)(A) giving to States the right to make BART determinations and allowing States to weigh the BART factors were included in the bill in the conference committee. H.R. Rep. No. 95-564, at *108 (1977) (Conf. Rep.). The conference report stated:

> The agreement clarifies that ***the State***, rather than the Administrator, identifies the source that impairs visibility in the Federal class I areas identified and thereby fall within the requirements of this section.
>
> * * *

> ***In establishing emission limitations for any source which impairs visibility, the State*** shall determine what constitutes 'best available retrofit technology' (as defined in this section) in establishing emission limitations on a ***source-by-source*** basis to be included in the state implementation plan so as to carry out the requirements of this section.

Id. (emphasis added); *see also* A Legislation History of the Clean Air Act Amendments of 1977, Sen. Comm. on Env't & Pub. Works, 95th Cong. at 535 (1978).[1]

Indeed, even the EPA acknowledges in the Final Rule that: "We agree that ***the CAA places the requirements for determining BART*** for BART-eligible sources ***on States***." 77 Fed. Reg. at 40153 (emphasis added).

The record before the EPA clearly established that the State of Nebraska followed § 169A(b)(2)(A) of the CAA, the Regional Haze Rule promulgated by EPA and Appendix Y of the Regional Haze Rule.[2] Despite Nebraska's compliance with statutory and regulatory requirements, EPA arbitrarily and capriciously refused to allow Nebraska to exercise its authority to determine what was "best suited to its particular situation". *Virginia v. EPA,* 108 F.3d at 1407.

THE EPA TRIES TO JUSTIFY ITS USURPATION OF AUTHORITY BY RE-FIGURING NEBRASKA'S COST ESTIMATES

The EPA does not claim that Nebraska failed to undertake the required five-step Regional Haze analysis required by the CAA. Rather, EPA chooses to reanalyze and refigure Nebraska's

[1] *See Moore v. District of Columbia*, 907 F.2d 165, 154 (D.C. Cir. 1990) (conference committee reports are "'the most persuasive evidence of congressional intent after statutory text itself,'" (quoting *Demby v. Schweicker*, 671 F.2d 507, 510 (D.C. Cir. 1981)).

[2] 70 Fed. Reg. 39104 (July 6, 2005). The Regional Haze Rule can also be found at 40 C.F.R. Part 51. References in this Petition will cite to the Federal Register publication.

cost estimate for the SO_2 BART cost estimates and now, for the first time, the NO_x cost estimates for the units at GGS.[3]

EPA's main justification to refigure Nebraska's cost estimates for SO_2 BART cost estimates hinges on the acceptance of the idea that States must strictly adhere to the provisions of EPA's Control Cost Manual.[4] A review of EPA's Appendix G reveals that EPA places a great deal of emphasis on the Control Cost Manual.[5] *See* Appendix G, Responses to Comments and Revisions to EPA's Evaluation of Costs of Flue Gas Desulfurization (FGD) Controls at Nebraska Public Power District (NPPD) Gerald Gentlemen [sic] Station (GGS) Units 1 & 2 (hereafter "Appendix G"), at 2-7. As noted by the Court in *American Corn Growers*, a BART determination must be made on a "source-specific basis." Costs that are unique to a source must be determined on something other than the generalizations found in the Control Cost Manual.[6] The EPA's Regional Haze Rule expressly provides that "[O]ne or more of the available control options may be eliminated from consideration because they are demonstrated to be technically

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[3] EPA failed to address any concern or disapproval of any cost estimates for the NO_x BART determination in the proposed rule. For the first time, and without prior public notice, EPA challenges the NO_x BART determination cost estimates.

[4] EPA Air Pollution Control Cost Manual, 6th Ed., EPA/452/B-02-001 (Jan. 2002).

[5] It must be noted that EPA disregards the Cost Control Manual when it disagrees with the EPA's current position. *See*, for example, pages 12-13 of Appendix G.

[6] It is questionable whether the Control Cost Manual is even relevant to the type of retrofit evaluation being conducted for GGS. The Control Cost Manual states, "[t]his Manual does not directly address the controls needed to control air pollution at electrical generating units (EGUs) because of the differences in accounting for utility sources." Control Cost Manual, at 1-3. However, assuming the Control Cost Manual is relevant, the Introduction section of the Manual makes clear that the assumptions contained in the Manual are generalized. For instance, it states, "From a regulatory standpoint, the Manual estimating procedure rests on the notion of the 'study' (or rough order of magnitude - ROM) estimate, nominally ***accurate to within ± 30%.*** This type of estimate is well suited to estimating control system costs intended for use in regulatory development because they ***do not require detailed site-specific information necessary for industry level analyses***. ... Moreover, the user has to be able to exercise 'engineering judgement' [sic] on those occasions when the procedures may need to be modified or disregarded." Control Cost Manual, at 1-7 (emphasis added).

infeasible or to have unacceptable energy, cost, or non-air quality environmental impacts ***on a case-by-case (or site-specific) basis***." 70 Fed. Reg. at 39164 (emphasis added). EPA's Appendix Y guidelines state that "[t]he basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual ..." *Id.* at 39166. It is clear the Regional Haze guidelines themselves allow Nebraska to use vendor-supplied bids for the site-specific sources at GGS and to consider other appropriate costs, regardless of whether such costs are set out in the Control Cost Manual.

NPPD requested Sargent & Lundy LLC ("S&L") to review and provide responses to EPA's Final Rule and appendixes thereto. S&L provided NPPD with a report, entitled "Nebraska Public Power District Gerald Gentleman Station (GGS) Comments," ("S&L Report") which is attached hereto as Exhibit 1 and incorporated herein by reference.[7] The S&L Report points out the serious flaws in EPA's evaluation and adjustments to Nebraska's cost estimations for SCR costs, EPA's untimely revisions to Nebraska's cost-effectiveness analysis for NO_x, and further reinforces the need for EPA to grant this Petition for Reconsideration. These will be further discussed below. The S&L Report also responds to EPA's discussion in the Final Rule and in Appendix G as to SO2.

[7] In preparation of comments on the Proposed Rule, NPPD consulted with S&L, which prepared a report entitled, "Gerald Gentleman Station (GGS) BART Comments." NPPD also consulted with Burns & McDonnell ("B&M") which also prepared a report entitled, "Gerald Gentleman Station (GGS) BART Comments." Both the S&L and B&M reports were submitted as attachments to NPPD's May 2, 2012, comments on the Proposed Rule. *See* Nebraska Regional Haze SIP Docket ID EPA-R07-OAR-2012-0158-0044. NPPD's comments on the Proposed Rule, and all attachments, including the S&L and B&M reports on the Proposed Rule, are incorporated herein by reference.

EPA also disapproved Nebraska's long-term strategy on the grounds that it relied on the deficient SO_2 BART determination at GGS. 77 Fed. Reg. at 40154. NPPD submits that because Nebraska's SO_2 BART determination was not defective for the reasons stated above in NPPD's comments on the Proposed Rule, which NPPD hereby incorporates herein by reference, Nebraska's long term strategy should be approved. *See* Nebraska Regional Haze SIP Docket ID EPA-R07-OAR-2012-0158-0044 (May 2, 2012).

EPA SHOULD HAVE PROVIDED NOTICE OF CHANGES THAT APPEAR IN THE FINAL RULE FOR THE FIRST TIME

EPA made several changes between the Proposed Rule and Final Rule that violate the Administrative Procedure Act ("APA") 5 U.S.C. § 551, *et seq.* Notice is sufficient under the APA only if it "affords interested parties a reasonable opportunity to participate in the rulemaking process, and if the parties have not been deprived of the opportunity to present relevant information by lack of notice that the issue was there." *Texas Alliance for Home Care Services v. Sebelius*, 811 F.Supp.2d 76, 99-100 (D. D.C. 2011). The test for determining whether notice was adequate, is "whether a new round of notice and comment would provide the first opportunity for interested parties to offer comments that could persuade the agency to modify its rule." *American Water Works Ass'n v. EPA,* 40 F.3d 1266, 1274 (D.C. Cir.1994).

The APA and courts interpreting the APA dictate that an agency's proposed rule and its final rule may differ "only insofar as the latter is a 'logical outgrowth' of the former." *See Environmental Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005). A final rule that finds "no roots in the agency's proposal" is not a logical outgrowth, because "something is not a logical outgrowth of nothing." *Id.* Additionally, there is no logical outgrowth where interested parties would have had to "divine [the agency's] unspoken thoughts." *Id.* (internal quotations omitted).

Section 307 of the CAA contains additional, "more stringent" notice and comment requirements than the APA. *See* 42 U.S.C. § 9607(d)(3); *Union Oil of California v. EPA*, 821 F.2d 678, 681 (D.C. Cir. 1987). Section 307 requires EPA to provide "a statement of its basis and purpose" of its rules, which should include a summary of "the factual data" on which the rule is based, "the methodology used in obtaining the data and in analyzing the data[,]" and the "major legal interpretations and policy considerations" underlying the rule. 42 U.S.C. § 7607(d)(3).

Here, EPA made two major changes between the Proposed and Final Rules that violate the notice and comment requirements of both the APA and CAA.

(1) The dollars per deciview per year cost threshold was unchallenged by EPA in the Proposed Rule

For the first time in the Final Rule, EPA indicated that Nebraska did not adequately justify the $40 million per deciview per year threshold Nebraska selected to determine the significance of visibility benefits. In the Final Rule, EPA stated that:

> The State is free to set the thresholds it chooses, as long as it provides support and a reasonable and adequate basis for the threshold. Nebraska set a cost threshold at $40 million/dv/year as reasonable for BART controls, however, the State did not provide justification or basis for why it chose that threshold.

77 Fed. Reg. at 40156. 77 Fed. Reg. at 40159. This conclusion conflicts with EPA's acceptance of the $40 million threshold in the Proposed Rule.

In the Proposed Rule, EPA did not question the $40 million threshold. Instead, in response to the SO2 BART analysis conducted, EPA merely noted that "In the SIP, Nebraska says that it used a $40,000,000/yr/dv threshold for determining what would be considered a reasonable investment for visibility improvement." *See* 77 Fed. Reg. at 12779. At no point did EPA suggest in the Proposed Rule that the $40 million threshold was unacceptable to EPA. In consequence, NPPD and the State of Nebraska were unlawfully deprived of the opportunity to comment on the basis for Nebraska's justification of the $40 million per deciview per year threshold.

Had EPA raised the issue of inadequate justification in the Proposed Rule, NPPD could have discussed the basis and appropriateness of the $40 million threshold and had the opportunity to "persuade the agency to modify its final rule," as required by *American Waterworks Association.*

Because EPA can point to nothing in the record to support its decision to belatedly disapprove of Nebraska's $40 million threshold, EPA's argument that Nebraska's SO_2 costs are over-estimated misses the point completely.

Assuming, for argument's sake only, that EPA is correct that the Control Cost Manual requires use of the so-called overnight cost method, EPA's own downward cost revisions show that Nebraska's $40,000,000 threshold is still exceeded by a large margin. For example, Table 3 of the Final Rule sets out EPA's estimates including the cost of obtaining water rights to operate FGD at GGS. 77 Fed. Reg. at 40162. The EPA's revised cost estimates, including water costs, result in a dollars per deciview cost of $107,531,566. *Id.*; *see also id.* at 40157, Table 1; S&L

Report attached to NPPD's Comments to the Proposed Rule, at 10 (May 2, 2012); *see also* S&L Report, at 25-28 (incorporating all of EPA's refigured costs). No matter how EPA refigures costs, the bottom line is that EPA's own cost estimates greatly exceed $40,000,000/yr/dv.

EPA acknowledges that "There is no particular threshold for determining significance of visibility benefit in the regional haze rule." 77 Fed. Reg. at 40156. In the Final Rule, EPA goes on to quote its own BART guidelines at 70 Fed. Reg. 39170: "However, we believe the States have flexibility in setting absolute thresholds, target levels of improvement, or *de minimis* levels since the deciview improvement must be weighed among the five factors, and States are free to determine the weight and significance to be assigned to each factor." *Id.* at 40156, note 14. Given these acknowledgments by the EPA, one can only deem EPA's decision to now reject Nebraska's $40 million threshold to be arbitrary and capricious.

In addition, EPA did not in the Proposed Rule, or Final Rule, determine or propose a reasonable threshold for the $/dv analysis. In contrast, Nebraska did so ***based on the information EPA Region 7 provided to the State***. *See* NDEQ State Implementation Plan for Regional Haze and Best Available Retrofit Technology (BART), at 69 (June 30, 2011) ("Nebraska Regional Haze SIP"); *see also*, EPA Region 7 letter to NDEQ (January 21, 2011). The 10 values cited by EPA in its January 21, 2011 letter range from a low of $4,192,276/dv to a high of $51,350,763/dv, with an average of approximately $20 million/dv. The second highest value reported by EPA was $35,192,308/dv. Thus, the value of $40,000,000/dv used, in part, by Nebraska to judge the economic suitability of visibility improvements was a very reasonable, if not highly conservative, treatment of the data that EPA itself had provided. The value used by Nebraska was about twice the mean value of the data provided by EPA, and fell between the ninth and tenth highest of 10 values reported by EPA, meaning that it was approximately the 95th percentile of the data EPA had provided. Given this information in the SIP, it is curious indeed that EPA chose to belatedly state in the Final Rule that Nebraska had not provided justification for the $40 million reasonableness threshold.

The Final Rule states "the BART guidelines list the dollars per deciview ratio as an additional cost effectiveness metric that can be employed along with dollars per ton in a BART evaluation." *Id.* at 40156. However, EPA goes on to claim that the dollars per deciview metric is more meaningful if cumulative visibility benefits are accounted for. This suggestion is contrary to EPA's own Regional Haze guidelines. The guidelines state:

> If the highest modeled effects are observed at the nearest Class I area, ***you may choose not to analyze*** the other Class I areas any further as additional analyses might be unwarranted.
>
> 70 Fed. Reg. at 39170 (emphasis added).

Nebraska determined that the Badlands was, in fact, the nearest Class I area with the highest modeled effects. Nebraska Regional Haze SIP, at 62-63, 67. Without being required to do so, Nebraska went ahead and also analyzed the benefits to be achieved at Wind Cave National Park on a cumulative basis. *Id.* at 63. Nebraska found that the average impairment improvement cost would be $73,333,547/yr/deciview, far in excess of the $40,000,000/dv reasonableness threshold. *Id.* at 63.

EPA's requirement to analyze cost effectiveness on a cumulative basis is countermanded by EPA's own final Regional Haze guidelines. [8]

(2) Cost estimates for NO_x at GGS were not challenged by EPA in the Proposed Rule

For the first time in the Final Rule, EPA refigured the NO_x cost estimates for the units at GGS. EPA's evaluation made a number of adjustments "in accordance with the Control Cost Manual" that resulted in a reduction of the capital cost estimate of approximately 33 percent. 77 Fed. Reg. at 40158. EPA made similar "adjustments" as to Nebraska's NO_x cost estimates for SCR, and determined that "Nebraska's NO_x BART determination for GGS is not supported by the record." *Id.* at 40159. These determinations starkly contrast with EPA's determination in the Proposed Rule that "***EPA agrees that the State's NO_x BART determination for GGS is reasonable***." 77 Fed. Reg. at 12779. (emphasis added)

The attached S&L Report discusses the changes and adjustments to Nebraska's NO_x BART determination for GGS made by EPA in the Final Rule. NPPD was not given any opportunity to comment on these changes and adjustments. The S&L Report notes the following:

EPA rejected NPPD's exclusion of an Engineering, Procurement, and Construction fee ("EPC fee") by incorrectly assuming that an EPC fee and engineering charge are equivalent. *See* S&L Report at 3-4. Assuming for the sake of argument that an EPC fee can be replaced with an engineering charge, the approach applied by EPA to determine the appropriate charge is

[8] Nebraska provided a reasoned decision not to do a cumulative analysis of all potential Class I areas. Nebraska relied on the fact that the CALPUFF model accuracy is very uncertain at distance above 200 km. *Id.* The Class I areas not analyzed by Nebraska are much further away.

inconsistent with the Control Cost Manual, as it was not based on a project-specific evaluation. *See* S&L Report at 4-5.

EPA similarly rejected Nebraska's determination of the equipment life for the SCR system by using the economic life of the equipment and the physical life of the entire system interchangeably. EPA further compared Nebraska's 20-year equipment life estimate with a 30-year estimate presented in a ***non-comparable*** academic paper and an estimate for a ***non-analogous*** SCR system. *See* S&L Report at 6-8. EPA also cites to its own statements in the New Mexico Regional Haze Federal Implementation Plan ("New Mexico RH FIP") to support its position. *See* Appendix E: EPA's evaluation of cost of Selective Catalytic Reduction (SCR) controls Nebraska Public Power District (NPPD) Gerald Gentlemen [sic] Station (GGS), Units 1 and 2, at 2-4.[9]

EPA rejected Nebraska's inclusion of escalation and AFUDC in its SCR cost estimate, and requires the use of the "overnight cost method" instead of the constant dollar approach described in the Control Cost Manual. *See* S&L Report at 9-10. The constant dollar approach was previously (and appropriately) utilized by EPA in Regional Haze determinations for other states.

EPA also rejected Nebraska's inclusion of a 20-percent cost contingency, despite the Control Cost Manual's allowance for inclusion of such contingency costs. *See* S&L Report at 11-12.

[9] The New Mexico RH FIP was challenged in court, and is currently stayed. EPA seeks to bootstrap its position by using its own statement which is currently stayed and under review.

Notwithstanding EPA's late attempt to refigure the NO_x costs, EPA determined that "the combination of the LNB/OFA controls proposed by the State in combination with the existing Transport Rule FIP, which already applies to Nebraska, satisfies the requirements for NO_x BART at GGS ..." 77 Fed. Reg. at 40160. This 180-degree change from the Proposed Rule is not a "logical outgrowth" of the prior determination, as required by the APA and interpreting case law. In addition, as EPA is aware, the Transport Rule is currently under judicial review. If it is stricken, in whole or in part, EPA's determination in the Final Rule that Nebraska's NO_x BART cost estimates were overstated might be argued by some to have repercussions affecting NPPD in a future Regional Haze proceeding.

EPA's CONTROL COST MANUAL WAS NEVER SUBMITTED TO PUBLIC NOTICE AND COMMENT

In the Final Rule, EPA requires use of an "overnight cost method," which EPA states is somehow required by the Control Cost Manual. NPPD is unaware that the "overnight cost method" is even mentioned in the Control Cost Manual. Regardless, based on the Control Cost Manual's non-apparent overnight costing method, EPA revised Nebraska's costs estimates. *See* Appendix G, at 4. EPA made similar downward revisions in Nebraska's SCR cost analysis. *See* Appendix G, at 10.

EPA's required use of the Control Cost Manual is not consistent with the Administrative Procedure Act because EPA tries to mandate use of the Control Cost Manual, i.e., EPA arbitrarily and capriciously seeks to require the use of the Control Cost Manual as if it were a promulgated rule.

As a preliminary matter, NPPD has been unable to locate any information either in the Control Cost Manual or through publicly accessible EPA databases that indicates that the Control Cost Manual was ever subjected to public notice and comment during its initial publication pre-1978 or during any of its five subsequent revisions. Courts, including the Eighth Circuit, have found that informal agency pronouncements, such as opinion letters, ***manuals***, and enforcement guidelines, "lack the force of law." *See Spirit Lake Tribe v. North Dakota*, 262 F.3d 732, 742 (8th Cir. 2001).

The Control Cost Manual lacks the force of law because it was not promulgated as a rule under the APA. The APA requires that proposed "substantive" or "legislative" rules be published in the Federal Register, and allow the public an opportunity to comment on the proposal. 5 U.S.C. § 553(b)-(c). The APA has an exemption to the public notice and comment requirements for "interpretative rules, general statements of policy, or rules of agency organization, procedure or practice." 5 U.S.C. § 553(b)(3)(A). However, case law has made clear that if an agency considers a pronouncement to be binding, it is subject to the APA notice and comment procedures. *See Natural Resources Defense Council v. EPA*, 643 F.3d 311, 321 (D.C. Cir. 2011) (finding that an agency guidance was legislative, not interpretive, that "EPA had no authority to issue without notice and comment."). The D.C. Circuit recently stated:

> an agency pronouncement will be considered binding as a practical matter if it either appears on its face to be binding, ***or is applied by the agency in a way that indicates it is binding***. It is enough for the agency's statement to 'purport to bind' those subject to it, that is, to be cast in 'mandatory language' so 'the affected private parties are reasonably led to believe that failure to conform will bring adverse consequences.'

Electronic Privacy Information Center v. U.S. Department of Homeland Security, 653 F.3d 1, 7 (D.C. Cir. 2011) (internal citations omitted).

Here, EPA enunciated its position that the Control Cost Manual is binding, by requiring Nebraska to utilize the "overnight cost method." As such, EPA is requiring the use of the Control Cost Manual "in a way that indicates it is binding," in violation of the APA.

In another recent D.C. Circuit case, the Court found that EPA could not rely on an agency guidance document that was not promulgated as a rule pursuant to the notice and comment requirements of the APA. *Natural Resources Defense Council v. EPA*, 643 F.3d 311, 321 (D.C. Cir. 2011). In that case, EPA asserted that a guidance document EPA administrators used in making decisions regarding Section 185 attainment alternatives was a "mere statement of policy." *Id.* The D.C. Circuit found that the "Guidance document changed the law" as "nothing in the statute, prior regulations, or case law authorize[d] EPA" to take the action allowed by the guidance document. *Id.* at 320-21. Therefore, the Court found that the "rule is not interpretive; it is legislative" and "EPA had no authority to issue without notice and comment." *Id.* at 321.

Mandating use of the Control Cost Manual also "changes the law." Appendix Y to the Regional Haze Rule states that control costs should be based on the Control Cost Manual "where possible" and lists the Control Cost Manual in an array of "general information sources to consider" or as an "example of supporting reference." *See* 70 Fed. Reg. at 39164, 39166. The Regional Haze Rule does not ***require*** use of the Control Cost Manual. EPA's actions in requiring use of the Control Cost Manual despite the flexibility provided by the regulations, allows the

Control Cost Manual to have the force of law without having undergone the necessary public notice and comment prerequisites of the APA.

NEBRASKA PROPERLY EXERCISED ITS JUDGMENT BY DETERMINING THAT DRY SORBENT INJECTION ("DSI") IS NOT COST EFFECTIVE

In the Final Rule, EPA states that it considers DSI to be cost effective and the visibility improvements to be significant at the closest Class I area, the Badlands, South Dakota. 77 Fed. Reg. at 40161. Here again, EPA is attempting to substitute its judgment for the judgment of the State which has the clear authority to determine what is suitable for Nebraska. Nebraska undertook the five-step analysis for DSI and concluded that:

> However, when comparing the dV improvement that would be gained and compared to the $/dV improvement to those provided by EPA Region 7, GGS Units 1 and 2 are substantially higher than any other facility included in Table 19. Furthermore, the visibility benefit gained does not outweigh the added burden of the added waste that would be generated through the control of SO_2 . . .
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> * * *
>
> [a]t this time, the NDEQ has determined that it is inappropriate to require the installation of DSI at GGS Units 1 and 2 due to the excessive cost per benefit in terms of visibility improvement (i.e., $/yr/dV) and the significance solid waste impact, and the uncertainty with regard to whether the waste would be considered a hazardous waste.

Nebraska SIP at p.70.

Contrary to the Regional Haze guidelines which do not require a State to analyze all Class I areas possibly affected by a source, EPA continues to suggest that Nebraska should have undertaken a cumulative review. In contrast to what EPA says in the Final Rule, Nebraska confirmed that the $/dV data information provided by EPA to Nebraska in its January 21, 2011 letter were all limited to a single Class I area and were not done on a cumulative basis. Nebraska Regional Haze SIP, Table 10.19 at p. 69. Table 10.19 shows that the use of DSI would have an annual cost of $64,458,000. In addition, the dollars per deciview cost would be $95,189,314. Such cost far exceeded Nebraska's reasonableness threshold of $40,000,000 per deciview. As has been pointed out in this Petition, two things must always be remembered about EPA's criticism of the $40,000,000 threshold in the Final Rule:

(1) EPA failed to disapprove the $40,000,000 threshold in the Proposed Rule and its attempt to do so in the Final Rule violates the Administrative Procedure Act's requirement to provide notice and public comment before a rule can be finalized.

(2) There is nothing in the record which EPA can point to which could substantiate a reasoned decision to now disapprove the $40,000,000 per deciview threshold.

EPA has provided no grounds upon which to undermine Nebraska's decision with respect to DSI.

CONCLUSION

For all these reasons, NPPD hereby respectfully requests EPA grant Reconsideration of the above-captioned rule and thereafter approve the entirety of Nebraska's Regional Haze SIP.

Respectfully submitted,

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Exhibit 1

Sargent & Lundy Report

Nebraska Public Power District Gerald Gentleman Station (GGS) Comments

Sargent & Lundy LLC

Docket ID No. EPA-R07-OAR-2012-0158
EPA Final Rule
Approval, Disapproval and Promulgation of Implementation Plans;
State of Nebraska; Regional Haze State Implementation Plan;
Federal Implementation Plan for Best Available Retrofit Technology Determination

Nebraska Public Power District
Gerald Gentleman Station (GGS) Comments
August 16, 2012

Introduction

On July 6, 2012, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a final rule accepting in part and rejecting in part the State of Nebraska's Regional Haze State Implementation Plan (RH SIP). Specifically, EPA rejected the sulfur dioxide (SO_2) Best Available Retrofit Technology (BART) determination published in the Nebraska RH SIP for Gerald Gentleman Station (GGS) Units 1 & 2. As an alternative to BART for SO_2 emissions from GGS, EPA finalized a Federal Implementation Plan (FIP) relying on the Transport Rule. EPA also found that Nebraska's NOx BART determination for GGS Units 1 & 2, by itself, was not supported by the record. Nevertheless, in conjunction with the Transport Rule FIP, EPA finalized its proposed approval of Nebraska's SIP as satisfying the requirements of the Regional Haze Rule with respect to BART for NOx.

Nebraska Public Power District (NPPD) requested that Sargent & Lundy LLC (S&L) review and provide responses to EPA comments included in the preamble to the Final Rule (hereinafter sometimes referred to as "Final RH FIP") and appendices attached thereto (included in the Docket EPA-R07-OAR-2012-0158). This report focuses on EPA's comments in the following appendices to the Final RH FIP:

Appendix C: Gerald Gentleman Spray Dryer Absorber BART Cost Analysis [Excel Worksheet]

Appendix D: Gerald Gentleman Selective Catalytic Reduction BART Cost Analysis [Excel Worksheet]

Appendix E: EPA's evaluation of cost of Selective Catalytic Reduction (SCR) controls Nebraska Public Power District (NPPD) Gerald Gentlemen [sic] Station (GGS), Units 1 and 2

Appendix G: Responses to comments and revisions to EPA's evaluation of cost of Flue Gas Desulfurization (FGD) controls at Nebraska Public Power District (NPPD) Gerald Gentlemen Station [sic] (GGS), Units 1 and 2

Comments Regarding BART for NOx at Gerald Gentleman Station

In the Nebraska RH SIP, the Nebraska Department of Environmental Quality (NDEQ) concluded, based on the relatively low incremental visibility improvement of adding selective catalytic reduction (SCR) to the low-NOx burner and overfire air (LNB/OFA) control systems at the additional cost of $5,445 incremental cost per ton, that requiring SCR as BART for GGS Units 1 & 2 was not warranted. This determination was based, in part, on cost estimates provided by NPPD for the installation and operation of SCR control systems at GGS. NDEQ determined that BART for NOx control at GGS would be the installation of LNB/OFA with an emission limitation of 0.23 lb/MMBtu, averaged across the two units. In its proposed rule for Nebraska's RH SIP, EPA approved Nebraska's NOx BART determination for GGS and accepted in toto, the SCR cost estimate and NOx control cost-effectiveness evaluation (77 Fed. Reg. 12779, col. 2).

Without prior notice, EPA revised its proposed rule and concluded that Nebraska's SCR costs were overestimated by including expenses inconsistent with EPA's Control Cost Manual.[1] (77 Fed. Reg. 40158, col. 2). EPA revised the SCR cost estimate by adjusting cost information provided by Nebraska. EPA made a number of adjustments to Nebraska's SCR cost estimate including:

- Adjustments to the engineering and procurement cost;
- Adjustments to the contingency cost;
- Deletion of escalation and allowance for funds used during construction (AFUDC);
- Increasing the SCR operational life from 20 years to 30 years;
- Adjusting the capital recovery factor;
- Recalculating the annualized charge taken to install the SCR (unit off-line); and
- Inclusion of a NOx control rate cost scenario of 0.05 lb/MMBtu.

EPA's reevaluation of the SCR cost estimate lowered the total capital cost of SCR for GGS Units 1 & 2 from $478,151,000 to $320,209,000 (for the 0.08 lb/MMBtu rate case), a reduction of approximately 33%. Using the revised equipment life, EPA was able to reduce the capital recovery factor (CRF) used to calculate the annualized cost of capital, resulting in a reduction of the total annualized cost of the SCR system from $57,251,000 to $39,467,000. Based on a reduction of annual NOx emissions of

[1] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002.

9,970 tpy, the incremental cost effectiveness of the SCR system improved from $5,445/ton to $3,622/ton.

Based on these revisions to the capital cost estimate, EPA determined that Nebraska's NOx BART determination of LNB/OFA for GGS Units 1 and 2 was not supported by the record (77 Fed. Reg. 40160, col. 2). Nevertheless, EPA concluded that Nebraska's BART determination of LNB/OFA, in conjunction with the Transport Rule FIP satisfies the requirements for NOx BART at GGS.

The following comments respond to changes made by EPA to the GGS SCR cost estimate and cost-effectiveness evaluation. Revisions made to the SCR cost estimate are summarized in Appendix D to the Final Rule "Gerald Gentleman Selective Catalytic Reduction BART Cost Analysis" (Excel spreadsheet) and described in Appendix E "EPA's evaluation of cost of Selective Catalytic Reduction (SCR) controls Nebraska Public Power District (NPPD) Gerald Gentlemen [sic] Station (GGS), Units 1 & 2".

Comment 1. Engineering, Procurement, and Construction Fee

NPPD included in its SCR cost estimate an EPC Fee equal to 20% of the total capital cost of the control system. EPA revised this line item, arguing that NPPD did not provide any discussion or explanation of this cost. EPA reduced the EPC Fee to 6.5% of the capital costs that were not supported by a vendor quote, and applied no EPC Fee to those costs supported by a vendor quote.

EPA made a similar change to NPPD's cost estimate for dry scrubbers in the proposed regional haze rule for Nebraska (77 Fed. Reg. 12770, the "Proposed RH FIP").[2] In comments submitted addressing this proposed change, NPPD pointed out the distinction between the EPC Fee and an engineering charge (see, Comments of Carl V. Weilert, P.E., Burns & McDonnell Engineering Co., Inc., pgs. 4-6, the "BMcD Report" incorporated herein by reference). NPPD showed that the EPC Fee is unique to the EPC contracting approach, and that EPA erroneously assumed that the EPC Fee was related to an engineering charge when it eliminated and adjusted the line item.

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[2] See, also, Technical Support Document (TSD) Nebraska Regional Haze Submittal, Prepared by: Chrissy Wolfersberger, Environmental Protection Specialist, U.S.EPA Region 7, February 2012.

As the BMcD Report pointed out, NPPD clearly noted that a principal assumption of its BART cost estimates for GGS was that an EPC contracting approach would be used to execute the project.[3] The EPC Fee represents a premium associated with the EPC contracting approach, in that the EPC contractor will increase the value of his 'fixed price' bid for an EPC project to account for the fact that he is taking the risk of price increases that may occur after contracts and subcontracts are awarded. It is reasonable to include an EPC Fee in a capital cost estimate that presumes the EPC contracting approach, as EPC contracts have become common in large-scale construction projects.

EPA was not persuaded by NPPD's explanation of its basis for the EPC Fee in the dry scrubber cost estimate. (See, Final RH FIP, Appendix G, pg. 2). Rather, in both SCR and dry scrubber cost estimates, EPA replaced the EPC Fee with an engineering line item charge, reiterating its finding that the EPC Fee used by NPPD was "high in comparison to other BART analyses we have seen such as the Oklahoma Gas and Electric [OG&E] Sooner and Muskogee BART analyses." EPA noted that the OG&E BART cost estimates estimated "engineering and procurement, an 'indirect capital cost,' as 6.5% of the total direct costs." EPA also noted that the Control Cost Manual estimates engineering and procurement as 10% of the purchased equipment cost. Finally, EPA argues that vendor proposals typically contain engineering and procurement costs associated with the quotes; thus, EPA did not apply an EPC Fee or engineering charge to equipment costs supported by a vendor quote. (Final RH FIP, Appendix G, pgs. 2-3).

NPPD continues to draw, contrary to EPA's position, a distinction between an EPC Fee and an engineering line item charge. The EPC Fee is a function of the contracting approach, while an engineering charge relates to work by engineering firms needed to retrofit the control system into the existing unit and design the ancillary balance-of-plant (BOP) equipment and systems. An engineering charge typically includes BOP engineering, A-E engineering, and Owner's engineering and construction management. Because the NPPD cost estimate presumed an EPC contracting approach, it included the EPC Fee. Conversely, the OG&E cost estimate was not premised on the EPC contracting approach and did not include an EPC Fee. Rather, the OG&E cost estimates included direct costs for BOP Contractor General & Administrative Cost (5% of BOP material and labor) and BOP Contract Profit (10% of BOP material and labor); and indirect line item costs, estimated as a function of the total direct costs, for Engineering/Procurement (6.5%), Construction Management (2.0%), Startup &

[3] See, "Basis of Estimate" on page 6 of 37 of Appendix A to the Revised BART Analysis for Gerald Gentleman Station, February 2008.

Commissioning Craft Support (2.0%), Operator Training & Manuals (0.55%), and Owner's Costs (5.0%). By relying on the OG&E cost estimate as its basis for changing the EPC Fee for the GGS SCR cost estimates, EPA continues to equate the EPC Fee to an engineering charge.

Even if EPA argued that an EPC Fee should not be included in a BART cost estimate, EPA's change was not consistent with the Control Cost Manual and was not based on a project-specific evaluation. The Control Cost Manual allows inclusion of indirect installation costs such as "engineering costs; construction and field expenses (i.e., costs for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies." (Cost Manual, Chapter 2, pg. 2.8). The SCR cost estimating example in the Control Cost Manual uses default indirect capital costs of: Engineering and Home Office Fees: 10% of total direct cost; General Facilities: 5% of total direct costs; and Process Contingency: 5% of total direct costs. Thus, not only was EPA's reliance on the OG&E cost estimate misplaced, EPA used an engineering cost factor of 6.5% (of the costs not supported by a vendor estimate) rather than the Control Cost Manual's 10% of total direct costs, and failed to include other indirect costs allowed by the manual.

Finally, EPA's statement that vendor proposals will typically contain engineering and procurement costs is incorrect. Budgetary quotes provided by equipment vendors to support NPPD's SCR cost estimate were provided to EPA and included in the administrative record.[4] In the preamble to the Final Rule, EPA noted "[w]e acknowledge that the vendor quotes provided in the docket (appendix 10.6 of the SIP) are redacted copies, omitting the name of the vendor and certain design parameters. However, we believe that adequate information was presented in order for EPA and the public to review the BART cost estimations." (77 Fed. Reg. 40160, col. 3).

EPA fails to recognize or acknowledge that the quotes provided to support the SCR cost estimate were designated as budgetary or indicative pricing quotes, and did not include all of the equipment, engineering, and installation costs that would be incurred to install the equipment. Furthermore, none of the quotes provided by equipment vendors presume an EPC contracting approach or include an EPC Fee. For example, the budgetary quote provided for the urea to ammonia system (which would be part of the overall SCR control system) includes a list of 23 items that would be supplied by others,

[4] See, Appendix 10.6 of the Nebraska RH SIP. Nebraska Public Power District Gerald Gentleman Station, BART Analysis Cost Estimate Basis – Vendor Quotes (Redacted Copies).

including: foundations, freeze protection, heat tracing panels and insulation of piping, structural steel modifications, installation and construction management, interconnecting piping, ductwork, and wiring of the furnished equipment. Similarly, the indicative price provided by the ID Fan vendor simply states that the price "does not include drive motors...inlet/outlet expansion joints or an outlet turning bend." Thus, EPA was incorrect when it failed to apply any engineering charge to the equipment costs supported by a vendor quote.

Comment 2. Capital Recovery Factor

Similar to its dry scrubber analysis, EPA took issue with NPPD's assumption of a 20-year amortization period for the SCR control system, and reiterates in Appendix E of the Final RH FIP its arguments as to why a longer operational life should be used in the calculation of the capital recovery factor (CRF). The CRF is used to annualize the cost of capital and is calculated as:[5]

$$\mathrm{CRF} = \left(\frac{i(1+i)^n}{(1+i)^n - 1}\right)$$

Where: i = interest rate
n = equipment life

EPA revised NPPD's CRF by increasing the NPPD's 20-year amortization life for the SCR control system to 30-years, asserting that equipment life is "clearly defined in the Control Cost Manual as being equal to the entire life of the control system." (Final RH FIP, Appendix G, pg. 13). EPA also argued that NPPD has not offered to execute an enforceable commitment to shut down after the 20 years (the economic life of the SCR control system); thus, EPA adopted an SCR operational life of 30 years. This change reduced the CRF from 0.08195 to 0.06691, or approximately 20%, which resulted in a direct reduction in the annualized capital recovery cost.

As in initial response to this change, NPPD reiterates that EPA never mentioned throughout the entire five-year rulemaking process that NDEQ relied on an incorrect CRF, nor did EPA criticize NPPD's 20-year equipment life for the SCR control system, both of which were clearly stated in NPPD's BART determination and NDEQ's BART determination and RH SIP. In fact, in the Proposed RH FIP, EPA stated that "the State's NOx BART determination for GGS is reasonable." (77 FR 112779, col. 2).

[5] Control Cost Manual, Chapter 2 Cost Estimation: Concepts and Methodology, Eq. 2.8a, pg. 2-21.

Nevertheless, EPA revised the equipment life and recalculated the CRF for the first time in its final rule, reducing annualized capital costs by approximately 20%.

Unlike the FGD cost analysis, the Control Cost Manual includes a chapter for developing study level cost estimates for SCR control systems.[6] The SCR capital cost example in the manual assumes a 20-year equipment life and interest rate of 7% to calculate CRF (Cost Manual, Section 4.2, Chapter 2, pg. 2-50).

In its Appendix E comments, EPA concluded that it would use a 30-year equipment life, noting that it is "mindful of the requirement in the BART Guidelines to incorporate site specific information into the cost analysis." EPA referenced its own response to comments for the New Mexico RH FIP regarding the San Juan Generating Station as the source of "site specific" information upon which it relied to extend the operational life of the NPPD SCR control systems to 30-years. (Final RH FIP, Appendix E, pg. 2). In its response to comments for the New Mexico RH FIP, EPA noted that the lifetime of a retrofit SCR, which is a metal frame packed with catalyst modules, is generally set equal to the remaining useful life of the facility, and that many utilities routinely specify 30+ year lifetimes in requests for proposals for SCR control systems. To support its claim, EPA referenced a technical article by S.D. Unwin and others ("Selective Catalytic Reduction (SCR) System Design and Operations: Quantitative Risk Analysis of Options"), and an SCR cost estimate prepared by S&L for the Navajo Generating Station (S&L Navajo Cost Analysis).

NPPD did not have an opportunity to comment on EPA's basis for extending the economic life of the SCR to 30-years. NPPD notes that the S.D. Unwin paper referenced by EPA describes risk-based methods to assess design and operation options for anhydrous ammonia-based SCR systems, and includes an analysis of "the health and economic risks associated with nonroutine, episodic releases of anhydrous ammonia to the environment." Although Unwin assumes an SCR system lifetime of 30-years to evaluate economic risks and annualized liabilities, the paper includes no technical evaluation of SCR control systems or discussion of the SCR design parameters or operating conditions, nor does it include a comparison of SCR control system capital costs and O&M costs as a function of equipment life. The article presents a risk assessment of anhydrous ammonia storage systems, and was clearly not intended to establish an SCR control system equipment life or amortization period for a BART evaluation.

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[6] See, Control Cost Manual, Section 4.2, Chapter 2 Selective Catalytic Reduction.

Relying on the SCR cost estimate prepared for the Navajo Generating Station in New Mexico is similarly misplaced. The Navajo Station consists of three existing coal-fired units each equipped with an existing hot-side electrostatic precipitator (HSESP) for particulate control. The design basis for the Navajo SCR cost estimate located the retrofit SCR control systems downstream of the units' existing HSESPs and upstream of new retrofit fabric filter baghouses. Thus, the Navajo SCRs would be considered a "low dust" application, that is, downstream of the primary particulate control device. Conversely, GGS Units 1 & 2 are currently equipped with fabric filter baghouses for particulate control, and, in order to achieve the flue gas temperatures needed for effective NOx control, the retrofit SCR control systems would be located upstream of the baghouses, in a high-dust application. EPA was incorrect when it applied the equipment life assumed in the Navajo SCR cost estimate to GGS.[7]

Although EPA describes the SCR control system as "a metal frame packed with catalyst modules," the SCR control system must be designed to operate in a harsh operating environment. Flue gas flow rates at the inlet to the high-dust SCR on GGS Units 1 or 2 would be in the range of 4,000,000 actual cubic feet per minute (acfm) with particulate loading of approximately 34,000 lb/hr, and temperatures in the range of 780 °F. The SCR box and internal structures would be subject to significant thermal stresses and abrasive particulate matter. In its Appendix E comments, EPA provides no site-specific design or operating information upon which to extend the operational or economic life of the GGS SCR control systems, and provided NPPD no opportunity to respond to this change.

A cost evaluation done in accordance with the Control Cost Manual should be based on the economic life of the equipment not the entire physical life of the control system. As noted in our comments submitted in response to the Proposed RH Rule, the term "economic life" is referenced throughout the manual. (Final RH FIP, Appendix G, pg. 12). Furthermore, by using a 30-year SCR equipment life, EPA is being inconsistent with its approach in other NOx BART determinations. For example, based on a review of BART determinations available from various jurisdictions, an equipment life of 20 years was used in the NOx BART determinations for Martin Drake Units 5 & 6, Comanche Units 1 & 2, Craig Units 1 & 2, Hayden Units 1 & 2, Four Corners Units 1 thru 4, Naughton Units 1 thru 3, Navajo Units 1 thru 3, and Nebraska City Unit 1. EPA even used a 20-year equipment life in its evaluation of SCR control systems of eight BART-eligible sources in its recently proposed Arizona RH FIP

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[7] Although EPA asserts that the Navajo SCR cost evaluation assumed a 30-year equipment, levelized annual costs presented in the report were calculated using a Capital Recovery Factor of 0.1159 based on an interest rate of 9.8% and amortization period of 20 years. (Navajo Generating Station – Units 1, 2, 3 SCR and Baghouse Capital Cost Estimate Report, SL-010214, August 17, 2010, Table 9-3).

(published in the Federal Register on July 20, 2012, approximately two-weeks after its publication of the Nebraska RH FIP).[8]

Finally, EPA's statement that NPPD must offer to execute an enforceable commitment to shut down after 20 years in order to use an SCR equipment life of 20 years is also inconsistent with its approach in other Regional Haze FIPs. For example, nowhere in the proposed Arizona Regional Haze FIP does EPA argue that the BART sources, including three units at the Apache Station, three units at the Cholla Power Plant, and two units at the Coronado Station, must agree to an enforceable commitment to shut down within 20-years to use the default 20-year amortization period. To the contrary, in Arizona EPA states "[s]ince we are not aware of any federally- or State-enforceable shut-down date for any of the affected sources, we have used the default 20-year amortization period in the EPA Cost Control Manual as the remaining useful life of the facilities considered in this proposed action." (77 FR 42854, col. 1).

Even though the SCR cost estimating example in the Control Cost Manual uses a 20-year amortization period to calculate CRF, EPA increased the amortization period for the GGS SCRs to 30-years, noting the BART Guideline requirement to incorporate site specific information into the cost analysis. However, the site specific analysis upon which EPA relied to increase the economic life of the GGS SCR control system includes an anhydrous ammonia risk analysis (with no engineering analysis of the control system operating conditions) and the Navajo BART cost estimate which was prepared for a low-dust SCR. Because all of these changes were made after publication of the proposed rule, NPPD had no opportunity to address the basis for EPA's revision of the SCR equipment life and its recalculation of the CRF.

Comment 3. Escalation and AFUDC

NPPD included line items for Escalation and AFUDC (Allowance for Funds Used During Construction) in its SCR cost estimate. Escalation represents the increase in project costs expected prior to actual installation of the control system. AFUDC accounts for the time value of money associated with the distribution of construction cash flows over the construction period. EPA excluded these costs from its SCR cost estimate for the same reasons discussed in its dry scrubber analysis. Specifically, EPA asserts that the "overnight" costing methodology described in the Control Cost Manual never allows inclusion of Escalation or AFUDC. (Final RH FIP, Appendix G, pgs. 4 and 10).

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[8] 77 Fed. Reg. 42834, July 20, 2012.

We reiterate our position that the Control Cost Manual describes a constant dollar approach to annualizing capital and operating costs, and that the term "overnight cost method" does not appear in the Control Cost Manual. The constant dollar approach described in the Cost Manual annualizes (in constant dollars) the costs of installation, maintenance, and operation of a pollution control device over the operational life of the control system. The manual recommends translating the costs in each future year to "year zero" using an equivalent uniform annual cash flow (EUAC) method. (Cost Manual, Section 1, Chapter 2, pg. 2-20). The EUAC method equalizes all future costs of maintenance and operation into equal annual payments over the life of the control system, with cash flows normalized to a single year, typically year zero. The constant dollar approach described in the Control Cost Manual only requires the analyst to establish a baseline year from which total annual costs can be equalized (in constant dollars) over the life of the control system. The manual does not dictate any specific baseline year, and does not prohibit the analyst from establishing the commercial operating date of the control system as the baseline year.

The approach used by S&L to develop the GGS SCR cost estimates was consistent with the methodology described in the Control Cost Manual. S&L defined the baseline (or zero) year for both units as the projected commercial operating date of the SCR control systems. Construction of an SCR control system can take from approximately 30 to 36 months; thus, it is reasonable to establish the commercial operating date as the baseline year from which future maintenance and O&M costs are calculated. Budgetary equipment cost estimates obtained from the equipment vendors were escalated to the baseline year. For consistency, annual O&M and auxiliary power costs were escalated to the baseline year, and calculated using a constant dollar approach over the operating life of the control equipment. This approach is consistent with the constant dollar approach described in the Cost Manual.

AFUDC is also a valid cost allowed by the Control Cost Manual methodology, and is consistent with the manual's constant dollar approach. Section 2.3.1 of the Control Cost Manual (Elements of Total Capital Investment or "TCI") describes the need for TCI to include all expenditures incurred during the construction phase of the project, including direct costs, indirect costs, fuel and consumables expended during start-up and testing, and other capitalized expenses. TCI, as defined in the Control Cost Manual, includes all costs required to purchase equipment needed for the control system (purchased equipment costs), the costs of labor and materials for installing that equipment (direct installation costs), costs for site preparation and building, working capital, and off-site facilities.[9] Thus, the Cost Manual allows the time value of money, measured by the real discount rate, to be incorporated into the cost estimate. The only items explicitly mentioned to be excluded are common facilities that already exist at the site.

In its response to comments, EPA reiterates its position that "the Control Cost Manual only allows the overnight cost method for a BART analysis" and that "AFUDC is never valid under the Control Cost Manual overnight cost approach." (Final RH FIP, Appendix G, pg. 10). However, NPPD notes that the term "overnight cost" is not found anywhere in the 752 pages of the Control Cost Manual. NPPD has also reviewed EPA's proposed and final Regional Haze FIPs for several states including the states of Oklahoma, North Dakota, New Mexico, the Navajo Nation, Montana, Wyoming, and Arkansas, and the technical support documents published by EPA to support its Regional Haze implementation plans in those states. It appears that the first time EPA raised the "overnight" cost assumption was in its technical support document for the final Oklahoma Regional Haze FIP published December 28, 2011 (76 Fed. Reg. 81778). Prior to that, EPA correctly argued that the Cost Manual required a constant dollar approach to estimating annualized control systems costs.[10]

Comment 4. Contingency

NPPD's capital cost estimate for the SCR control systems included a contingency cost estimated at 20% of the total equipment, material, labor, and indirect capital costs. EPA argues that no information was provided to justify the need for this calculation, noting that "[u]nlike dry scrubbers, the Control Cost Manual does have a specific section that treats SCR cost estimation." EPA argues that because NPPD did not support this cost, it would use the Control Cost Manual methodology to calculate contingency. The SCR example in the Control Cost Manual includes a process contingency calculated as 5% of the total direct cost, and a project contingency calculated as 15% of the sum of the total direct and indirect costs. EPA's approach reduces the contingency cost from $72.8 to $51.8M.

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9 Cost Manual, Section 1, Chapter 2 Cost Estimation: Concepts and Methodology, page 2-5.

10 See, e.g., "Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2, Muskogee Units 4 & 5, and Northeastern Units 3 & 4, Prepared for Ellen Belk U.S. EPA Region 6, Prepared by Phyllis Fox, Ph.D., PE, October 2010, "The cost metric estimated in the Manual is real or constant-dollar costs in that the effect of inflation has been removed." (pg. 9), and "These costs are not part of the constant dollar approach found in the EPA Control Cost Manual and should not be included in BART cost-effectiveness analyses." (pg. 12).

The Control Cost Manual defines indirect installation costs to include "costs such as; construction and contractor fees, startup and testing, inventory capital, and any process and project contingency costs."[11] Contingency is intended to represent unforeseeable elements of cost, particularly in fixed investment estimates, which previous experience has shown to be statistically likely to occur. Thus, as EPA acknowledges, the Control Cost Manual clearly allows contingency in the capital cost estimate, the only question is what level of contingency is appropriate.

The Control Cost Manual allows the analyst to include both process and project contingencies in an estimate of the indirect capital costs, but does not specify any particular methodology for estimating an appropriate level of contingency. NPPD asserts, based on the level of engineering completed in the development of the BART SCR cost estimates for GGS, that a 20% contingency is appropriate. As explained in the Revised BART Analysis for GGS Units 1 & 2, cost estimates were based on: (1) site-specific conceptual design layouts for each of the potential retrofit technologies; (2) major equipment costs were based on vendor budgetary quotes; and (3) material costs were developed based on project-specific quantities and recent commodity costs.[12] However, no project specific engineering or design of the control systems or ancillary systems needed to install the control equipment, and no balance-of-plant engineering was done to prepare the capital cost estimates. Contingency is based on the level of project definition, typically expressed as the percent of complete design and engineering. Given the level of project-specific engineering and design completed for the GGS SCR projects a 20% contingency is appropriate.

As EPA noted in its comments on equipment life, CRF and engineering costs, the analyst should be mindful of the requirement in the BART Guidelines to incorporate site-specific information into the cost analysis. Based on the level of engineering completed for the GGS SCR retrofit projects, S&L concluded that a 20% contingency was appropriate. With no site-specific analysis of equipment life or engineering costs, EPA diverted from the Control Cost Manual example by increasing the SCR equipment life from 20 years to 30 years, and by calculating engineering costs based on a 6.5% factor rather than the 10% factor used in the SCR example. Here, however, EPA argues that no information

[11] See, Control Cost Manual, Section 4.2, Chapter 1 (SNCR), pg. 1-32. See also, Section 4.2, Chapter 2 (SCR), pgs. 2-34; and Section 1, Chapter 2 (Cost Estimation: Concepts and Methodology), pg. 2-5.

[12] Nebraska Public Power District REVISED Best Available Retrofit Technology (BART) Analysis for Units 1 & 2 Gerald Gentleman Station, Sutherland, Nebraska, February 2008, pg. 9.

was provided to justify the need for a 20% contingency, and defaulted to the contingencies used in the Cost Manual's SCR example.

Comment 5. NOx Level of Control

In its BART determination, originally submitted to NDEQ in August 2007, NPPD assumed a controlled NOx emission level of 0.08 lb/MMBtu with SCR. In its Appendix E comments, EPA noted that the BART Guidelines require that the most stringent level of control be evaluated, and asserted that an SCR level of control of 0.05 lb/MMBtu was appropriate. EPA's basis for this more stringent level of control was its New Mexico RH FIP (published as a final rule on August 22, 2011) in which it "found that an SCR level of control of 0.05 lbs/MMBtu, based on a 30 boiler operating data average was appropriate for the San Juan Generating Station." (Final RH FIP, Appendix E, pg. 4). Based on this finding, EPA recalculated SCR cost effectiveness at GGS using both a controlled NOx emission rate of 0.08 lb/MMBtu and a controlled rate of 0.05 lb/MMBtu.

As an initial response, NPPD notes that the New Mexico RH FIP has been challenged, and implementation of the FIP is currently stayed. Furthermore, NPPD had no opportunity to comment on the more stringent level of NOx control. In response to EPA's draft rule in NM, Tucson Electric Power Company, an owner participant of San Juan Generating Station (SJGS) Units 1 & 2, argued that the NOx "emission rate proposed by EPA for SCR was not practically achievable by retrofit technology at SJGS." TEP noted that EPA provided no site-specific, technical information to support its proposed NOx emission rate, but relied on "an informal and unscientific survey of certain other facilities equipped with SCR. Many of these other facilities are new construction as apposed to a retrofit of SCR at an existing facility."[13] Subsequently, EPA retained the more stringent NOx emission rate in its final NM FIP; however, the New Mexico Environment Department Office of General Counsel submitted a Petition for Reconsideration and Stay of the Final Rule.[14] The Governor of New Mexico also sent a letter to EPA asking that EPA issue a stay of the New Mexico RH FIP, and on July 2, 2012, EPA Administrator Lisa Jackson signed a 90-day stay of the FIP. The New Mexico RH FIP, upon which

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[13] Letter from Tucson Electric Power Company to EPA Region 6, Re: EPA Docket No. EPA-R06-OAR-2010-0846 (76 FR 491; January 5, 2011), April 4, 2011, pg. 7.

[14] New Mexico Environment Department Office of General Counsel, Petition for Reconsideration and Stay of EPA's Final Rule: "Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination" (Docket No. EPA-R06-OAR-2010-0846), October 21, 2011.

EPA relies to make its determination that the GGS SCR control systems could achieve a more stringent NOx emission rate, is still being reviewed and scrutinized. Furthermore, NPPD should have an opportunity to evaluate and comment on the "informal and unscientific survey" upon which EPA relied to establish the NOx emission rate for the San Juan Generating Station.

EPA also noted in the preamble to the Final Rule that it agreed "with the commenter's suggestion that if the visibility modeling had been conducted at a more stringent control rate of 0.05 lb/MMBtu, which an SCR is capable of achieving, the visibility improvements would likely be greater than what is stated in Nebraska's SIP submission, and within a range many states and EPA have found to be significant for control." (77 Fed. Reg. pg. 40159, col. 2). Although NPPD did not have an opportunity to comment on this statement, we note that several factors go into the CALPUFF visibility impact modeling including, but not necessarily limited to, the controlled NOx emission rate, NO/NO_2 ratio, ammonia (NH_3) slip, PM emissions, and PM speciation. All of these variables would change with the lower controlled NOx scenario, especially the NH_3 slip value that may be needed to ensure a controlled NOx emission rate of 0.05 lb/MMBtu. Increased NH_3 slip could have a significant impact on visibility modeling; however, these impacts cannot be quantified without modeling the specific emission rates. There is no information in the record that a more stringent NOx emission rate would provide any significant improvement in modeled visibility impacts.

Comment 6. Effect of NOx Removal Efficiency Assumption on Cost

EPA used a novel approach to quantify the effect of NOx removal efficiency on capital and O&M costs. EPA used its IPM Planning Model to estimate the percent increase in capital costs and variable O&M costs and applied these ratios to its revised SCR cost estimate. NPPD has not had an opportunity to review this approach; however, the IPM Planning Model is generally used by EPA to analyze the projected impact of environmental policies on the electric power sector. EPA describes the model as "a multi-regional, dynamic, deterministic linear programming modeling of the U.S. electric power sector."[15] The model is not typically used to calculate project-specific air pollution control system costs.

Relying on the IPM Model cost worksheets to compare capital and O&M costs at various levels of control would not provide a project-specific cost comparison. For example, increasing the size of the

[15] See, http://www.epa.gov/airmarkt/progsregs/epa-ipm/

SCR reactor box to achieve a more stringent NOx emission rate may impact other existing structures at the facility resulting in significant additional costs, beyond those of the larger SCR reactor. The IPM Model cost worksheets do not include this type of site-specific information, and EPA did not do a site-specific evaluation. NPPD did not have an opportunity to evaluate the technical feasibility and balance-of-plant impacts associated with designing the GGS SCR to achieve a controlled NOx emission rate of 0.05 lb/MMBtu.

We also note that EPA calculated the incremental reduction in annual NOx emissions with the SCR control system, and thus the incremental cost effectiveness of the SCR control system, using a baseline NOx emission rate of 0.23 lb/MMBtu (with LNB/OFA) a full load heat input of 15,175.5 MMBtu/hr (total for both units) and an annual capacity factor of 100% (or 132,937,380 MMBtu/yr). (Final RH FIP, Appendix D, cells H58 and H59). To be consistent with its approach in other BART determinations, and consistent with the BART Guidelines, annual emission reductions should be calculated based on average actual NOx emissions over the baseline period.[16] Annual NOx emissions from GGS Units 1 & 2 should be calculated based on an annual heat input of 111,548,727 MMBtu/yr, which represents the actual average annual heat input to both units during the baseline period (or a capacity factor of approximately 84%). Using the actual annual heat input, baseline NOx emissions (with LNB/OFA) are reduced from 15,288 tpy to 12,828 tpy, and annual NOx emission reductions are reduced from 9,970 tpy to 8,266 tpy. This change would affect the incremental cost effectiveness of the SCR control system.

Comment 7. SCR Cost Effectiveness

In the Final RH FIP, EPA revised the total annual cost of the SCR system at GGS by eliminating Escalation and AFUDC, replacing the EPC Fee with an engineering line item charge based on the BART cost estimate prepared for the OG&E generating stations, revised the calculation of Contingency, and extended the economic life of the SCR from 20 years to 30 years based on the New Mexico RH FIP. EPA also calculated annual NOx emissions assuming 100% annual capacity factor, rather than calculating representative annual NOx emissions as required by the BART Guidelines. All of these changes reduced total annual costs of the SCR system by approximately 33%, from $54,281,000 to $36,507,000, and improved the incremental cost effectiveness of SCR from $5,445/ton to $3,662/ton.

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[16] See, 70 Fed. Reg. 39167, col. 1.

EPA's revisions to the SCR cost estimate have a significant impact of the SCR cost effectiveness evaluation. For example, using all of EPA's cost revisions, but using the appropriate baseline heat input and NOx emissions, the incremental cost effectiveness of the SCR system increases to $4,416/ton ($36,507,000 / 8,266 tons). Recalculating total annual costs using an equipment life of 20 years and including an engineering charge of 10% (both default factors in the Control Cost Manual SCR example), the incremental cost effectiveness of the SCR system increases to $5,093/ton ($42,611,000 / 8,266 tons). Because of the significant impact these changes have on the calculation of SCR cost effectiveness, NPPD should have an opportunity to review and comment on the revisions made by EPA.

Comments Regarding BART for SO_2 at Gerald Gentlemen Station

Unlike the Nebraska BART determination for NOx at GGS, EPA did comment on Nebraska's BART determination for SO_2 at GGS in its Proposed RH FIP.[17] EPA's comments generally focused on the cost estimates prepared for the GGS dry scrubbers. EPA revised the cost estimates by changing certain line items and excluding other line items, which EPA concluded, were not allowed by the Control Cost Manual. NPPD, through its engineering consultants Sargent & Lundy LLC (S&L) and Burns & McDonnell (BMcD) submitted comments in response to EPA's proposed changes to the FGD cost estimates.[18] In the Final RH FIP, EPA retained almost all of its revisions to the FGD cost estimates, and provided additional comments in Appendix G to the Final RH FIP, "Responses to comments and revisions to EPA's evaluation of cost of Flue Gas Desulfurization (FGD) controls at Nebraska Public Power District (NPPD) Gerald Gentlemen [sic] Station (GGS), Units 1 and 2." Additional discussion of EPA's revisions to the GGS FGD cost estimates, and EPA comments included in Appendix G of the Final RH FIP, is provided below.

Comment 1. Baseline SO_2 Emissions

In its original and revised BART Determinations for GGS, submitted in August 2007 and February 2008, respectively, NPPD used an annual SO_2 emission rate of 49,785 tpy to calculate control system

[17] See, 77 Fed. Reg. 12770, March 2, 2012, Appendix A: EPA's evaluation of cost of Flue Gas Desulfurization (FGD) controls Nebraska Public Power District (NPPD) Gerald Gentlemen [sic] Station (GGS), Units 1 and 2.

[18] Docket ID No. EPA-R07-OAR-2012-0158, Gerald Gentleman Station (GGS) BART Comments: Kenneth J. Snell, J.D., P.E., Sargent & Lundy LLC (the "S&L Report"); and Carl V. Weilert, P.E., Burns & McDonnell Engineering Co., Inc. (the "BMcD Report"), both of which are incorporated herein by reference.

operating costs and to evaluate the cost effectiveness of retrofit flue gas desulfurization (FGD) control systems.[19] In its comments to the Proposed RH FIP, EPA noted that the Appendix Y BART Guidelines state that baseline emissions should represent a realistic depiction of anticipated annual emissions for the source. (70 Fed. Reg. 39167, col. 1). EPA noted that it saw no indications that GGS's future operating practices were projected to deviate from the past; therefore, EPA revised the GGS baseline annual SO_2 emissions to 31,513 tons/yr. A baseline annual SO_2 emission rate of 31,513 tpy reflects the average total station emissions for GGS Units 1 & 2 during the three year baseline period 2001-2003. (Proposed RH FIP, Appendix A, pg. 8).

In comments to the Proposed RH FIP, NPPD pointed out that by changing the baseline SO_2 emissions EPA was being inconsistent with its approach in other BART determinations. (S&L Report, pg. 8). However, NPPD did not object to EPA lowering the SO_2 emissions baseline at GGS, nor did NPPD suggest that EPA should deviate from the approach described in the BART Guidelines. In fact, after pointing out inconsistencies in the approach used by EPA to establish baseline annual emissions in BART determinations, NPPD incorporated EPA's revisions into its cost effectiveness calculations. (S&L Report, pg. 10).

Rather than addressing this inconsistency, EPA simply noted that it took "NPPD's objection into account" and, contrary to the position it took in the Proposed RH FIP, EPA increased baseline SO_2 emissions from GGS Units 1 & 2 to 49,785 tpy. EPA provided no explanation for increasing baseline annual SO_2 emissions from GGS Units 1 & 2, and EPA provided no basis for deviating from the BART Guidelines. Rather than sticking with its original change, as it did with practically all other comments provided by NPPD, EPA took the opportunity to increase baseline SO_2 emissions from GGS Units 1 &

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[19] See, NPPD Revised BART Determination for the Gerald Gentleman Station, February 2008, pg. 14, Table 2. NPPD calculated baseline annual SO_2 emissions based on an emission rate of 0.767 lb/MMBtu, a maximum heat input to both units of 15,175.5 MMBtu/hr, and a 100% capacity factor. As noted in the Revised BART Determination, the approach used by NPPD to calculate baseline annual SO_2 emissions "greatly overstates emissions levels (and hence impacts on downwind Class I areas) since it is calculated by using the maximum 24-hour emissions realized over the 3-year baseline period (2001-2003), at a 100% capacity factor." (Revised BART Determination, Table 2, footnote). Nevertheless, NPPD used a baseline SO_2 emission rate of 49,785 tpy to provide consistency with the emission rate used to model visibility impacts from the station. Guidance provided in Appendix Y of the Regional Haze Rule recommends visibility impact modeling based on the "24-hour average actual emission rate from the highest emitting day of the meteorological period modeled." (70 Fed. Reg. 39170, col. 2). To provide consistency between the modeled visibility impacts, control system operating costs, and control system cost-effectiveness, NPPD calculated baseline annual SO_2 emissions using the same SO_2 emission rate.

2, and used the higher SO_2 baseline to calculate cost-effectiveness of the FGD control system.[20] This approach deviates from EPA's own comments to the Proposed RH FIP and is inconsistent with the BART Guidelines.

As EPA noted in the Proposed RH FIP, baseline annual emissions used in BART cost-effectiveness evaluations should be based on a realistic depiction of anticipated annual emissions for the source. EPA should have, as it advocated in the Proposed RH FIP and as recommended by the Appendix Y BART Guidelines, used an annual baseline SO_2 emission rate of 31,513 tpy to calculate annual SO_2 emission reductions, annual control system O&M costs, and control system cost effectiveness.

Comment 2. EPC Fee

In the Proposed RH FIP, EPA concluded that the EPC Fee used in the NPPD scrubber cost estimates was "high in comparison to other BART analyses" and revised the fee down to 6.5% of the total direct costs that were not supported by a budgetary vendor quote. (Proposed RH FIP, Appendix A, pg. 3). Based on its finding that vendor quotes typically contain engineering and procurement costs associated with the equipment being supplied, EPA applied no engineering charge to items supported by a vendor quote.

In response to this proposed change, NPPD, through its engineering consultant Burns & McDonnell Engineering Co., Inc. ("BMcD"), pointed out the distinction between the EPC Fee and an engineering line item charge. BMcD showed that the EPC Fee is unique to the EPC contracting approach, and that EPA erroneously assumed that the EPC Fee was related to an engineering charge when it eliminated and adjusted the line item. (BMcD Report, pg. 5, incorporated herein by reference). In its comments to the Final RH FIP, EPA acknowledged that "an EPC contract is a costing mechanism in which a contractor assumes the risks and responsibility for all elements of engineering, procurement, and construction, in exchange for a cost premium." Nevertheless, EPA retained this change and replaced the EPC Fee with and engineering line item charge. (Final RH FIP, Appendix G, pg. 3).

As noted in our response to Comment 1 of the SCR cost revisions, there is a distinction between an EPC Fee and an engineering line item charge. The EPC fee is a function of the contracting approach, while an engineering charge relates to work by engineering firms needed to retrofit the control system

[20] See, cost-effectiveness calculations in Appendix C-revised to the Final RH FIP, and 77 Fed. Reg. 40162, Table 3 (calculating cost effectiveness taking into consideration the cost of obtaining water rights to operate FGD at GGS).

into the existing unit and design the ancillary BOP equipment and systems. (See, Response to SCR Comment 1, incorporated herein by reference). NPPD's FGD cost estimate presumed an EPC contracting approach, while the OG&E BART cost estimates were not premised on an EPC contracting approach. Because the NPPD cost estimate presumed an EPC contracting approach, it included the EPC Fee.

In its comments to the Final RH FIP, EPA asserts that "NPPD did not provide evidence that engineering, planning, and construction was not included for those items covered by its vendor quotes." (Final RH FIP, Appendix G, pg. 3). However, all vendor quotes obtained to support the GGS scrubber cost estimate were provided and included in the record.[21] A cursory review of the quotes reveals that quotes provided by the equipment vendors include budgetary or indicative price quotes only, and are not offers to sell. (See, Vendor Quotes, pdf pg. 56 of 146). Moreover, the quotes are limited in scope. For example, the quote provided by a dry FGD vendor included a list of items not included in the dry FGD budget cost estimate provided, including (Vendor Quotes, pdf pg. 55 of 146):

- lime unloading, handling and storage equipment up to the silos;
- ID fans or booster fans;
- ash handling system;
- foundations and civil work;
- elevated building slabs;
- all electrical equipment;
- elevator in absorber area;
- controls;
- insulation and lagging;
- field painting;
- guarantee testing;
- installation;
- construction supervision;
- connecting piping and pip racks;
- ductwork, including support steel, insulation and lagging; and
- existing plant design review and/or verification.

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[21] See, Nebraska Public Power District Gerald Gentleman Station, BART Analysis Cost Estimate Basis – Vendor Quotes (Redacted Copies).

Similarly, the indicative price provided by the second FGD vendor noted that "[t]he pricing is for material supply only. No erection is included." (Vendor Quotes, pdf. pg. 57 of 146). This quote also includes a list of items excluded from the Dry FGD scope, including: all ductwork and support structures, DCS programming and hardware, elevators, buildings and enclosures, BOP including foundations and lighting; insulation and lagging, erection, ID fans, and lime and ash conveying systems. Clearly, the vendor quotes upon which NPPD relied to prepare its capital cost estimate did not include an EPC Fee and did not include an indirect engineering & procurement line item charge. Removing the EPA Fee and revising the engineering line item charge to zero for equipment costs supported by a vendor quote, as EPA did, was clearly incorrect.

Finally, as we noted in our comments to the SCR cost changes, even if EPA is arguing that the Control Cost Manual does not allow inclusion of an EPC Fee, EPA provides no basis for using the engineering charge multiplier from the OG&E cost estimate, and fails to include other indirect installation costs allowed by the Control Cost Manual. The Control Cost Manual allows inclusion of indirect installation costs such as "engineering costs; construction and field expenses (i.e., costs for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies." (Cost Manual, Chapter 2, pg. 2.8). Calculating the engineering charge based on 6.5% of the direct costs that are not supported by a vendor quote is inconsistent with the approach in the Control Cost Manual, and significantly underestimates the engineering costs that NPPD would incur to install retrofit FGD controls on GGS Units 1 & 2.

Comments 4 and 6. Escalation and AFUDC

In the Proposed RH FIP, EPA excluded both Escalation and AFUDC from the FGD cost estimate, arguing that neither line item is valid under the "overnight cost approach" employed by the Control Cost Manual (Proposed RH FIP, Appendix A, pg. 4). In response to the proposed change, NPPD submitted comments supporting its position that both line items represent real costs that NPPD will incur as part of an FGD control system retrofit project, and that both costs can in fact be included in a cost estimate prepared in accordance with the approach described in the manual. (BMcD Report, pgs. 8 and 11, incorporated herein by reference). Nevertheless, based on its conclusion that "the intent of the

Control Cost Manual is to compute and compare cost-effectiveness on the basis of overnight costs," EPA retained these revisions and excluded both line items from the capital cost estimate.

NPPD reiterates its position that the Control Cost Manual describes a constant dollar approach to calculating and annualized capital and O&M costs, and that both Escalation and AFUDC costs can be included in a capital cost estimate prepared in accordance with the constant dollar approach described in the manual. Comments submitted by NPPD in response to the Proposed RH FIP (BMcD Report), and comments provided in response to Comment 3 of the SCR cost revisionnss above, are incorporated herein by reference to support this conclusion.

Comment 5. Contingency

In its comments to the Proposed RH FIP, EPA reduced NPPD's calculation of Contingency in the FGD cost estimate for GGS (calculated based on 20% of the equipment, material, labor and indirect costs) to 3% of the purchased equipment costs. EPA relied on the Control Cost Manual's example cost estimate for a wet acid gas scrubber, the control system which EPA characterized as being most similar to the proposed controls, as the basis for this change. (Proposed RH FIP, Appendix A, pg. 5).

NPPD, through its engineering consultant BMcD, submitted comments to this proposed change showing, among other things, that the "contingency" included in the GGS FGD cost estimate had characteristics of, and served the same function as, both a contingency and a retrofit factor, and that "in selecting the value of this contingency, S&L took into account the complexity of the Dry FGD retrofit to the existing facility at GGS and its prior experience in the execution of similar utility scale Dry FGD retrofit projects." (BMcD Report, pg. 10, incorporated herein by reference). Given the level of engineering completed in the development of the FGD capital cost estimates, BMcD concluded that EPA's reduction of the contingency from 20% to 3% was not reasonable and was not supported by a correct and full reading of the Control Cost Manual. (Id., at 11).

EPA rejected NPPD's comments, finding that contingencies and retrofit factors are intended for different things and that the Control Cost Manual treats them separately (Final RH FIP, Appendix G, pg. 7). EPA found no reason to include a retrofit factor in the FGD cost estimate, but stated that it was revising the calculation of contingency based on 3% of the purchased equipment cost for those capital costs supported by vendor quotes and 20% for the remaining purchased equipment costs that are not directly supported by vendor quotes.

Although EPA acknowledged that the Control Cost Manual allows for both a contingency and a retrofit factor, EPA argues that the manual treats them separately. Therefore, EPA stated that it "reviewed NPPD's BART report and other information in the record in order to ascertain the degree of difficulty that S&L anticipated for the retrofit dry scrubbers in relation to other similar retrofits." (Final RH FIP, Appendix G, pg. 8). EPA noted that S&L, provided "some insight into the anticipated retrofit difficulty," but concluded that the description provided did "not shed light on whether this difficulty is less than, average, or greater than other similar retrofits." Therefore, EPA did not apply a retrofit factor or take retrofit difficulty into its calculation of contingency.

NPPD provided a detailed description of the retrofit challenges associated with installing FGD control systems on GGS Units 1 & 2, which EPA referenced in full in the Final RH FIP. (Final RH FIP, Appendix G pg. 8). Retrofit challenges that NPPD would have to address to install FGD control systems on GGS Units 1 & 2 include, but are not necessarily limited to, locating the dry scrubber vessels downstream of the existing baghouse control systems, reversing flue gas flow through the existing baghouses, reinforcing the baghouses and other existing duct work to withstand additional negative pressures, and demolishing existing structures to make room for the FGD and lime handling systems. As S&L noted in its description of the FGD design for GGS, all of these "design features are unique to the GGS dry FGD control system and represent <u>significant retrofit challenges</u>." (Final RH FIP, Appendix G, pg., 8, emphasis added). EPA was incorrect when it stated that "there is nothing in the record that would lead us to conclude that the retrofit difficulty is greater than average, or that it justifies a retrofit factor greater than 1.0." EPA should have applied a retrofit factor to the GGS FGD capital cost estimate, or, consistent with the approach used by S&L, taken retrofit difficulty into consideration to establish a project-specific contingency factor.

EPA's approach to calculating contingency for the retrofit FGD control projects at GGS is flawed for several reasons. First, as noted above, there is ample description in the record to justify a retrofit factor, or, at a minimum, incorporate retrofit difficulty into a project-specific contingency factor. Second, FGD control systems designed to control SO_2 emissions from a large coal-fired boiler differ significantly from the wet acid gas scrubbers described in Section 5, Chapter 1 of the Control Cost Manual. EPA's reliance on the Cost Manual's example for a wet acid gas scrubber to establish a project-specific contingency for the GGS FGD projects is misplaced. (BMcD Report, pg. 11). Third, all of the vendor quotes used to develop the capital cost estimates for the FGD control systems are included in the administrative record, and EPA was incorrect when it concluded that it "would expect that the need for contingencies for these costs items would be minimized." (Final RH FIP, Appendix G, pg. 6). All of the budgetary quotes provided by equipment vendors were limited in scope, and clearly state that they do not include any BOP engineering, design, or ancillary equipment needed to install and operate the control systems. EPA's conclusion that costs based on budgetary vendor quotes would require minimal contingency is not supported by the record.

Comment 7. Capital Recovery Factor and Equipment Life

In its comments to the Proposed RH FIP, EPA revised the equipment life for the retrofit FGD control system at GGS from 20 years to 30 years, and recalculated the capital recovery factor (CRF) used to annualize capital costs. (Proposed RH FIP, Appendix A, pg. 5). NPPD submitted comments in response to this change, pointing out, among other things, that the term "economic life" is used to calculate CRF throughout the Control Cost Manual, and that requiring NPPD to use a 30-year amortization period in its economic analysis of the FGD control systems is inconsistent with EPA's approach in other BART determinations. (S&L Report, pgs. 3-6, incorporated herein by reference). In the Final RH FIP, EPA retained the 30-year amortization period, concluding that "control equipment life is clearly defined in the Control Cost Manual as being equal to the entire life of the control." (Final RH FIP, Appendix G, pg. 13).

As noted in our response to Comment 2 of the SCR cost revisions, a cost evaluation done in accordance with the Control Cost Manual should be based on the economic life of the equipment not the entire physical life of the control system. Furthermore, requiring NPPD to evaluate the cost effectiveness of the FGD control systems using a 30-year amortization period is inconsistent with EPA's approach in other BART determinations. (See, S&L Report, pg. 6-5). In response to NPPD's comment that other FGD BART determinations used shorter amortization periods, EPA noted that the Montana regional haze action by EPA Region 8 (which evaluated cost-effectiveness of FGD control systems using an equipment life of 15-years) was "a proposal, as opposed to the final actions we have taken in our Oklahoma and New Mexico FIPs." (Final RH FIP, Appendix G, pg. 14). However, NPPD notes that implementation of both the Oklahoma and New Mexico regional haze FIPs have been stayed pending resolution of legal challenges to the rules.

Finally, as with the amortization period used in the SCR cost evaluation, EPA argues that "when the lifetime of the scrubber effects that BART determination, as here, we require a federally-enforceable restriction preventing further operation after a date certain, i.e., the requested 20 years." (Final RH FIP,

Appendix G pg. 14, citing 70 FR 39169). As noted in our response to Comment 2 of the SCR cost revisions, requiring GGS to accept a federally-enforceable restriction preventing operation beyond 20-years in order to use an FGD equipment life of 20 years in its cost evaluation is inconsistent with its approach in other RH FIPs. For example, in the recently proposed Arizona RH FIP, EPA states that "[s]ince we are not aware of any federally- or State-enforceable shut-down date for any of the affected sources, we have used the default 20-year amortization period in the EPA Cost Control Manual as the remaining useful life of the facilities considered in the proposed action." (77 Fed. Reg. 42854, col. 1). Requiring NPPD to use a 30-year amortization period to evaluate the cost effectiveness of FGD control systems at GGS is inconsistent with the definition of "equipment life" as that term is used in the Control Cost Manual, and is inconsistent with the approach EPA has used in other BART determinations.

Comment 8. Variable O&M Calculation

In the Proposed RH FIP, EPA used a two step approach to revise both the fixed and variable O&M costs of the FGD control system at GGS. First, EPA adjusted both line items by multiplying them by the ratio of EPA's and NPPD's capital recovery factor (CRF), then, EPA adjusted the variable O&M costs further by the difference between NPPD's and EPA's calculation of annual SO_2 emission reductions. (Final RH FIP, Appendix G, pg. 16). NPPD submitted a response to both of these revisions. (S&L Report, pg. 8, incorporated herein by reference).

In the Final RH FIP, EPA noted that it applied the first adjustment to the O&M costs because the costs were identified as "levelized" costs in the GGS cost estimate. (Final RH FIP, Appendix G, pg. 16). However, as NPPD showed in its comments to the proposed rule, the approach used to levelized O&M costs is unrelated to the calculation of the capital recovery factor. (S&L Report, pg. 8). Annualized O&M costs in the NPPD cost estimate were calculated by levelizing the first year O&M costs over the 20-year operating life of the control system using a real interest rate (i.e., with inflation removed from the discount rate). This approach is consistent with the constant dollar approach described in the Control Cost Manual. Extending the operating life of the equipment to 30 years would not reduce the levelized O&M costs as EPA suggests, and EPA was incorrect when it adjusted these costs by the ratio of the capital recovery factors.

Based on NPPD's comments to the Proposed RH Rule, EPA decided that it would forego this adjustment, noting that the revision appears in Appendix C-revised of the Final RH FIP. (Final RH

FIP, Appendix G, pg. 17). However, in Appendix C-revised, EPA continued to apply this adjustment to the fixed O&M costs (cell H47) and to the levelized outage cost (cell H51). Like the variable O&M costs, these line items should not be adjusted by the ratio of the capital recovery factors.

EPA secondarily reduced the variable O&M costs by the difference between NPPD's and EPA's calculation of annual SO_2 emission reductions. (Final RH FIP, Appendix G, pg. 16). EPA claims that it took this approach because the variable cost calculations (e.g., calculations for lime consumption, water, auxiliary power, and solid waste disposal costs) do not appear in the Revised BART Analysis, and that EPA had "no choice but to continue to estimate these costs, using our best judgment, and the information that is in the record." (Id., at 17). Without specifically calculating variable O&M costs for each SO_2 control scenario, NPPD accepted EPA's approach, as, in general, variable O&M costs will be a function of the quantity of SO_2 removed from the flue gas stream. (S&L Report, pg. 10).

The most significant change EPA made between the Proposed and Final RH FIPs, was its calculation of baseline SO_2 annual emissions. As discussed in response to Comment 1 of the FGD cost revisions above, contrary to the position it took in the Proposed RH FIP and contrary to guidance in the Appendix Y BART Guideline, EPA increased baseline SO_2 emissions from GGS Units 1 & 2 from 31,513 tpy to 49,785 tpy. This had the affect of increasing the tons of SO_2 removed in the cost effectiveness evaluation, and making the variable O&M cost adjustment moot. However, as discussed in our response to Comment 1 of the FGD cost revisions, baseline annual emissions used in BART cost-effectiveness evaluations should be based on a realistic depiction of anticipated annual emissions for the source. EPA should have, as it advocated in the Proposed RH FIP, used an annual baseline SO_2 emission rate of 31,513 tpy to calculate annual SO_2 emission reductions, annual control system variable O&M costs, and control system cost effectiveness.

Revised Cost Effectiveness Calculations

Taking into consideration EPA's comments to the Final RH FIP, we have revised the Appendix C-revised FGD cost-effectiveness calculations as follows:

a. The engineering line item charge was recalculated based on 10% of the total direct costs (to be more consistent with the Control Cost Manual).
b. Annualized fixed O&M and outage costs were revised by removing EPA's adjustment based on the ratio of the capital recovery factors.

c. Annual SO_2 emission reductions were revised using a baseline annual SO_2 emission rate of 31,513 tpy (and a corresponding annual removal rate of 23,147 @ 0.15 lb/MMBtu).

d. Variable O&M costs were revised based on the quantity of SO_2 removed.

e. The annualized cost of obtaining water rights to operate the FGD control system at GGS were included in the calculation of total annual costs. (See, EPA comments to the Final RH FIP, 77 Fed. Reg. 40162, Table 3).

Incorporating these changes, all of which were proposed by EPA, results in an average cost effectiveness of the FGD control system of $3,413/ton, and more than $100 million/dv (based on 0.78 dv improvement at the nearest Class I area). These revisions are shown in the following table. Revising or reinstating the EPC Fee, Escalation, AFUDC, Contingency, and revising the amortization period of the FGD control systems back to 20-years would only results in the FGD control system being less cost effective.

1	Gerald Gentleman Spray Dryer Absorber BART Cost Analysis - revised					
2		GGS	EPA Appendix C-revised		Revised	
3		**TOTAL STATION**	**TOTAL STATION**		**TOTAL STATION**	
4	**Capital Costs**					
5	[redacted]	**$ 96,754,000**	**$ 96,754,000**		**$ 96,754,000**	
6	Civil/SiteWork	$ 4,987,000	$ 4,987,000		$ 4,987,000	
7	Flue Gas System/Ductwork	$ 98,228,000	$ 98,228,000		$ 98,228,000	
8	Baghouse Modifications	**$ 26,568,000**	**$ 26,568,000**		**$ 26,568,000**	
9	[redacted]	**$ 19,671,000**	**$ 19,671,000**		**$ 19,671,000**	
10	[redacted]	**$ 12,518,000**	**$ 12,518,000**		**$ 12,518,000**	
11	Common Structures/Buildings	$ 14,616,000	$ 14,616,000		$ 14,616,000	
12	[redacted]	$ 16,284,000	$ 16,284,000		$ 16,284,000	
13	[redacted]	**$ 21,529,000**	**$ 21,529,000**		**$ 21,529,000**	
14	Track Ladders and Switches	$ 2,604,000	$ 2,604,000		$ 2,604,000	
15	Miscellaneous Mechanical Items	$ 8,712,000	$ 8,712,000		$ 8,712,000	
16	Pipe Rack	$ 6,570,000	$ 6,570,000		$ 6,570,000	
17	[redacted]	**$ 13,006,000**	**$ 13,006,000**		**$ 13,006,000**	
18	Instrumentation and Controls	$ 3,513,000	$ 3,513,000		$ 3,513,000	
19	Electrical Modifications	$ 25,816,000	$ 25,816,000		$ 25,816,000	
20	Mobilization/Demobilization - 1% of Labor	$ 1,890,000	$ 1,890,000		$ 1,890,000	
21	Cost Due to Overtime - 5-10's	$ 25,368,000	$ 25,368,000		$ 25,368,000	
22	Per Diem	$ 25,656,000	$ 25,656,000		$ 25,656,000	
23	Spare Parts - 3% of Equipment	$ 3,262,000	$ 3,262,000		$ 3,262,000	
24	Freight	$ 4,706,000	$ 4,706,000		$ 4,706,000	
25	General & Administration - 5% of Material and Labor	$ 14,401,000	$ 14,401,000		$ 14,401,000	
26	Profit - 10% of Material and Labor	$ 28,801,000	$ 28,801,000		$ 28,801,000	
27	EPC Fee - 20% of Total Cost	$ 100,367,000	$ 18,551,910	Revised to 6.5% of capital costs (bold) not supported by vendor quotes	$ 47,546,000	Changed to 10% of the total direct costs
28	**Subtotal**	$ 575,827,000	$ 494,011,910		$ 523,006,000	

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		GGS	EPA Appendix C-revised		Revised	
		TOTAL STATION	**TOTAL STATION**		**TOTAL STATION**	
29						
30	**Other Costs**					
31	Indirect	$ 47,452,000	$ 47,452,000	Added back bond fees, stated to be 2.5% of $200M, which were excluded in the proposal	$ 47,452,000	
32	Escalation	$ 120,449,000	0	Not allowed under the Control Cost Manual	0	Escalation is allowed under the constant dollar approach
33	Sales/Use Tax	$ 11,077,000	$ 11,077,000		$ 11,077,000	
34	Contingency	$ 148,745,000	$ 44,368,060	Revised to 3% of purchased equipment cost for capital costs with vendor quotes; 20% for those without	$ 44,368,060	Did not revise Contingency, however, EPA's approach is not correct.
35	AFUDC	$ 83,302,000	0	Not allowed under the Control Cost Manual	0	AFUDC is allowed under the constant dollar approach
36	**Subtotal**	$ 411,025,000	$ 102,897,060		$ 102,897,060	
37						
38	**Total Capital Cost**	$ 986,852,000	$ 596,909,000		$ 625,903,000	
39						
40	**Capital Recovery Factor (CRF)**	0.0820	0.0669	Revised based on a 30 year service life	0.0669	Did not revise, but amortization period of FGD should be 20 years.
41	**Levelized Capital Cost**	$ 80,875,000				
42						
43	**Total Capital Cost (w/ fan sized for FGD only)**	$ 981,591,000	$ 591,648,000		$ 620,642,000	
44	**Levelized Capital Cost (w/fan sized for FGD only)**	**$ 80,013,000**	**$ 39,591,000**		**$ 41,531,000**	
45						

		GGS	EPA Appendix C-revised		Revised	
		TOTAL STATION	TOTAL STATION		TOTAL STATION	
46	**O&M Costs**					
47	Levelized Fixed O&M	$ 7,812,000	$ 6,378,774		$ 7,812,000	Fixed O&M is not a function of the CRF
48	GGS Levelized Variable O&M (0.15 lbs/MMBtu)	$ 19,994,000	$ 19,994,000	Assumed to be the same as GGS, for ease of addressing S&L comment	$ 11,624,000	Adjusted based on SO2 removal rate
49						
50	**Levelizeed O&M Cost**	$ 27,806,000	$ 26,372,774		$ 19,436,000	
51	Levelized Outage Cost	$ 698,000	$ 569,942		$ 698,000	The levelized outage cost is not a function of the CRF
	Annualized Cost to Obain Water Rights (EPA)				$ 17,343,757	Added in annual cost of obtaining water rights to operate the FGD
52	Total Levelized Capital, Outage, and O&M Cost	**$ 108,517,000**	**$ 66,534,000**		**$ 79,009,000**	
53						
54	**GGS SO2 baseline**	49,785				
55	**GGS SO2 reduction (based on 0.15 lbs/MMBtu)**	**39,815**				
56	**GGS cost effectiveness ($/ton)**	**2,726**				
57						
58	**EPA SO2 baseline**		49,785	Revised from proposed SO2 baseline of 31,512 to no e same as GGS	31,513	Revised as required by Appendix Y
59	**EPA SO2 Reduction (0.15 lbs/MMBtu)**		39,815		23,147	
60	**EPA Cost Effectiveness (0.15 lbs/MMBtu)**		**$ 1,671**		**$ 3,413**	
	Modeled Improvement at Badlands Class I Area (dv)	0.78	0.78		0.78	
	Average Cost Effectiveness ($/dv)	**$ 139,124,359**	**$ 85,300,000**		**$ 101,293,590**	